MONTHLY SYSTEM OPERATOR AND SYSTEM PERFORMANCE REPORT

FOR THE ELECTRICITY AUTHORITY

Transpower New Zealand Limited

February 2019

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

Table of Contents

Report Purpose iv
Commentary 5

System operator performance 6
1 Compliance 6
2 Market design and system enhancement project updates 6
3 Outage planning and coordination 7
4 Performance metrics 8
5 Actions taken 8
6 Cost-of-services reporting 8
7 Technical advisory hours and services. 8
8 Separation of Transpower roles 8
9 Customer 9

System performance 9
10 Operational and system events 9
11 Frequency fluctuations 10
12 Voltage management 13
13 Security notices 13
14 Grid emergencies 13
15 Security of supply 13
16 Ancillary services 14

Appendix A: Discretion 15
Appendix B: Ancillary Services Graphs 16

Report Purpose

This report is Transpower's review of its performance as system operator for February 2019, in accordance with clause 3.14 of the Electricity Industry Participation Code 2010 (the Code).

A detailed system performance report (Code obligated) is provided for the information of the Electricity Authority (Authority).

Commentary

This section provides an update for the month, the remainder of the report provides supporting detail in two sections:

- System operator performance, and
- System performance.

Real Time Pricing (RTP) – We are assisting the Authority with the consultation paper on the remaining elements of the RTP design and supporting the Authority at an industry briefing on 29 March.

Dispatch Service Enhancement (DSE) - The design of the IST changes to implement the new ICCP and web services connection service are completed, and build is nearing completion.

Credible Event Review - A schedule for the work during 2019 is now in place. Studies will begin on a "trial" busbar – Manapouri. We intend to seek feedback on this with a group of selected industry participants and the Authority in the second half of March before proceeding with the remainder of the studies.

Outage watchlist for dry year - We are creating a watchlist of outages that may be affected by a dry winter. We have identified possible outages that would constrain thermal generation, constrain on hydro generation or limit HVDC transfer.

Outage Planning Forum, 18 March - This year we are using this opportunity to discuss outage planning issues with participants. In our role as system operator, this will include explaining our current communications and notifications for outages, and discussing improvements, as well as discussing the use of POCP and NZGB.

Outage Planning Policy - This went live in February and can be found on our website. It includes how we deal with the considerations Transpower, as grid owner, must make in planning outages, and those that are relevant to our system operator role in assessing outages and notifying interested parties. These are the areas where we want to be clearer about our approach and how we maintain impartiality in our system operator service.

HVDC lessons learned working group - A working group from Transpower's system operator and grid owner planning groups is progressing short-term improvements to outage planning and real-time outage management.

We have also published a guideline document to explain when we, as system operator, will publish notifications and assessments.

Operations senior leaders visit to Mercury and Genesis - As part of the refresh work that Operations is scoping, the Senior Leadership team met with both Mercury and Genesis in Auckland. These meetings were an opportunity for us to receive direct feedback from the customer around our performance and the deliverables we produce, including whether they are still fit for purpose.

System operator performance

1 Compliance

We reported one breach of the Electricity Participation Code 2010 in February. This related to an error in an update to the Reserves Management Tool (RMT) in January 2018. The impact meant that reserves from a generator were not recognised as procured during scheduling, so additional reserves were purchased. We are working with the Electricity Authority to establish the market impact of this error. The error was not identified for 12 months; analysis found this affected 76 trading periods across the year. We are instigating an independent audit of change controls for RMT. At no time was the system less secure as a result of this error.

Appendix A shows instances where the system operator has applied discretion under 13.70 of the Code.

2 Market design and system enhancement project updates

Progress against high value, in-flight market design and service enhancement projects is included below along with details of any variances from the current Capex Plan.

Real Time Pricing (RTP)

We are assisting the Authority with the consultation paper on the remaining elements of the RTP design and supporting the Authority at an industry briefing on 29 March.

Dispatch Service Enhancement (DSE)

The design of the IST changes to implement the new ICCP and web services connection service are completed, and build is nearing completion. The cost allocation model was drafted and socialised with the Authority in time for the industry workshop held on 1 March 2019. Work in March will include finalising the cost allocation model and developing a transition plan by 22 March.

Situational Intelligence

We are working with the preferred vendor to refine the approach and estimates for the pilot phase. The delivery business case is due to be completed at the end of March 2019. We have agreed to provide an update to the Electricity Authority in March 2019.

System Operations Tools

The delivery business case for this project, to further develop on line system stability assessments, is due at the end of March.

Credible Event Review

A schedule for the work during 2019 is now in place. The methodology for the busbar (frequency) studies has now been agreed and studies will begin on a “trial” busbar –

Manapouri. We intend to seek feedback on this with a group of selected industry participants and the Authority in the second half of March before proceeding with the remainder of the studies.

National Market for Instantaneous Reserves (NMIR) refinements

The changes to implement this project are on track for late March 2019.

Reserve Management Tool Roadmap and Market Events Notification 1

The investigation approval documents outlining the approach, schedule and cost of investigation phases for these projects are underway.

3 Outage planning and coordination

Volume of outage planning

February was a very busy month for outages and the outage change rate was extremely high. Of the 654 outages there were 158 changes within 12 weeks out. Outage numbers are climbing and there are 28 key outages that we expect will need extra system operator assessment in the next 10 weeks, or that could potentially cause security violations through timing or currency issues.

Outage watchlist for dry year

Longer term we are creating a watchlist of outages that may be affected by a dry winter. We have identified possible outages that would constrain thermal generation, constrain on hydro generation or limit HVDC transfer.

Outage Planning Forum, 18 March

This year we are using this opportunity to discuss outage planning issues with participants. In our role as system operator, this will include explaining our current communications and notifications for outages, and discussing improvements, as well as discussing the use of POCP and NZGB.

Outage Planning Policy

This went live in February and can be found on our website. This is an internal policy that we have discussed with industry. It draws on our Electricity Industry Participation Code obligations, particularly those which deal with the considerations Transpower, as grid owner, must make in planning outages, and those that are relevant to our system operator role in assessing outages and notifying interested parties. These are the areas where we want to be clearer about our approach and how we maintain impartiality in our system operator service.

Guideline for publishing notifications and assessments

We also published a guideline document to explain when we, as system operator, will publish notifications and assessments. This outlines the triggers we will use in providing the assessments. It covers general situations but particularly two key regions of the electricity system:

- Upper North Island or Zone 1 voltage stability
- The HVDC

The development and publication of this document was additionally influenced by the 'HVDC lessons learned work'.

HVDC lessons learned working group

A working group from real-time and planning groups in Operations plus Transpower's Grid Service Delivery group is progressing short-term improvements to outage planning and real-time outage management which will:

- improve communication and understanding within Transpower and with industry before and during 'sensitive' outages
- provide earlier, predictable signals to participants of tight situations where actions may be needed from generators, load or transmission
- clarify decision-making processes
- improve clarity around our grid owner and system operator roles.

4 Performance metrics

System operator performance against the performance metrics for the financial year as required by SOSPA 12.3 (a) will be provided in the next quarterly report.

5 Actions taken

A full list of actions taken regarding the system operator business plan, statutory objective work plan, participant survey responses and any remedial plan, as required by SOSPA 12.3 (b) will be provided in the next quarterly report.

6 Cost-of-services reporting

The feasibility study into implementing annual cost-of-services reporting to the Authority is required in financial year 2 (SOSPA 12.6). This was completed in September 2017. We will present the draft version of the reporting to the Authority in Q3 report (period ending March 2019).

7 Technical advisory hours and services.

Technical advisory hours and a summary of technical advisory services to which those hours related (SOSPA 12.3 (d) refers) will be provided in the next quarterly report.

8 Separation of Transpower roles

Since the creation of the Operations division and implementation of Transpower-wide training on role impartiality and conflict of interest, we have had a number of issues raised to the register. These issues are being handled in accordance with Transpower's policy for managing conflicts of interest.

There were two issues raised and one closed in the conflict of interest register in February. The first new issue relates to a staff interest declared in a planned generator build and commissioning. The second new issue relates to security and availability of

data after recent software updates. The closed issue related to potential interactions between EMS and system operator functions.

As noted in section 3 of this report, the Outage Planning Policy particularly looked at areas where perceived conflict may occur. We want our approach to be clearer to the industry on how we plan and assess outages and how we maintain impartiality in our roles.

A summary of the open items raised on the conflict of interest register is set out below:

- System operator staff involvement with grid owner project
- Outage planning policy (currently being consulted with industry)
- Ensuring consistent information provided for outage information
- Management of actions from role impartiality review
- Actions during HVDC outage
- Staff interest in an industry participant project
- Security and availability of data

9 Customer

As part of the refresh work that Operations is scoping, the Senior Leadership team met with both Mercury and Genesis in Auckland. These meetings were an opportunity for us to receive direct feedback from the customer around our performance and the deliverables we produce, including whether they are still fit for purpose.

System performance

10 Operational and system events

Black Start Simulation

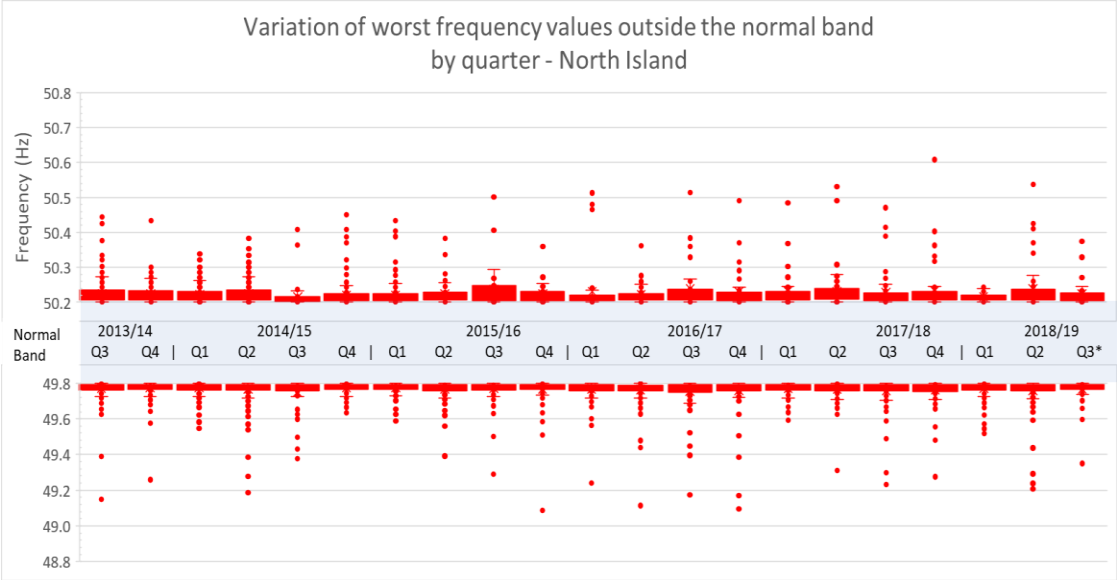
We ran a South Island joint Black Start simulation on the 19 February which was once again a valuable exercise. All four simulation rooms were used with industry participants from Contact, Meridian and NZAS taking part. The system operations and grid owner teams ran the two South Island Black Start contingency plans in parallel and then automatically synchronised the islands at Waitaki. As part of this exercise, we used the new automated control switching sequence, which replaces voice-given instructions. This functionality worked well and it is likely be built into the actual plan as an option.

11 Frequency fluctuations

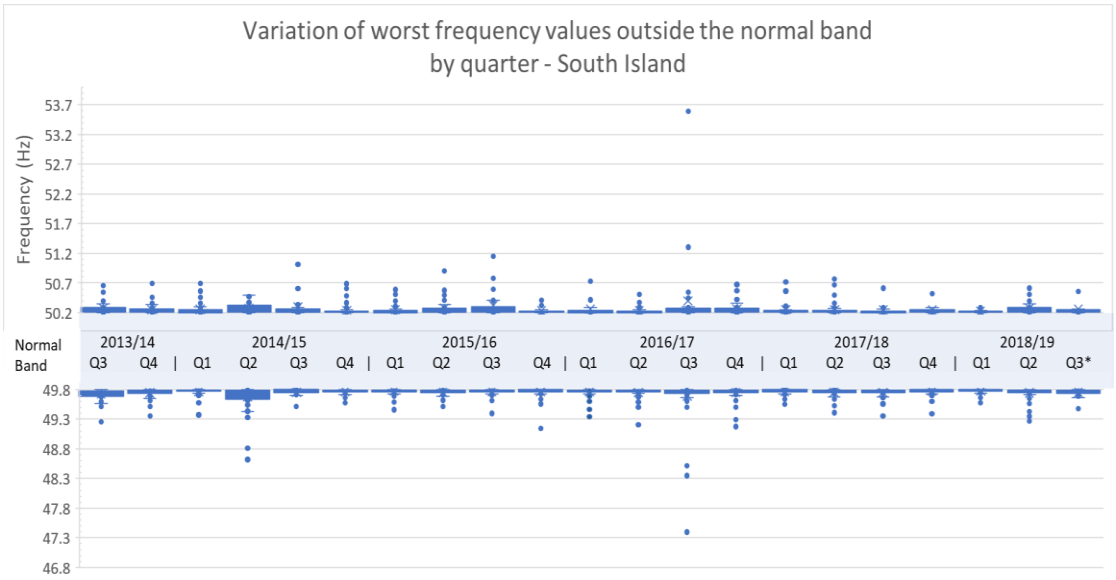
11.1 Maintain frequency in normal band (Frequency value)

The following charts show the distribution of the worst frequency excursion outside the normal band (49.8 to 50.2 Hz) during the reporting period.

North Island



South Island



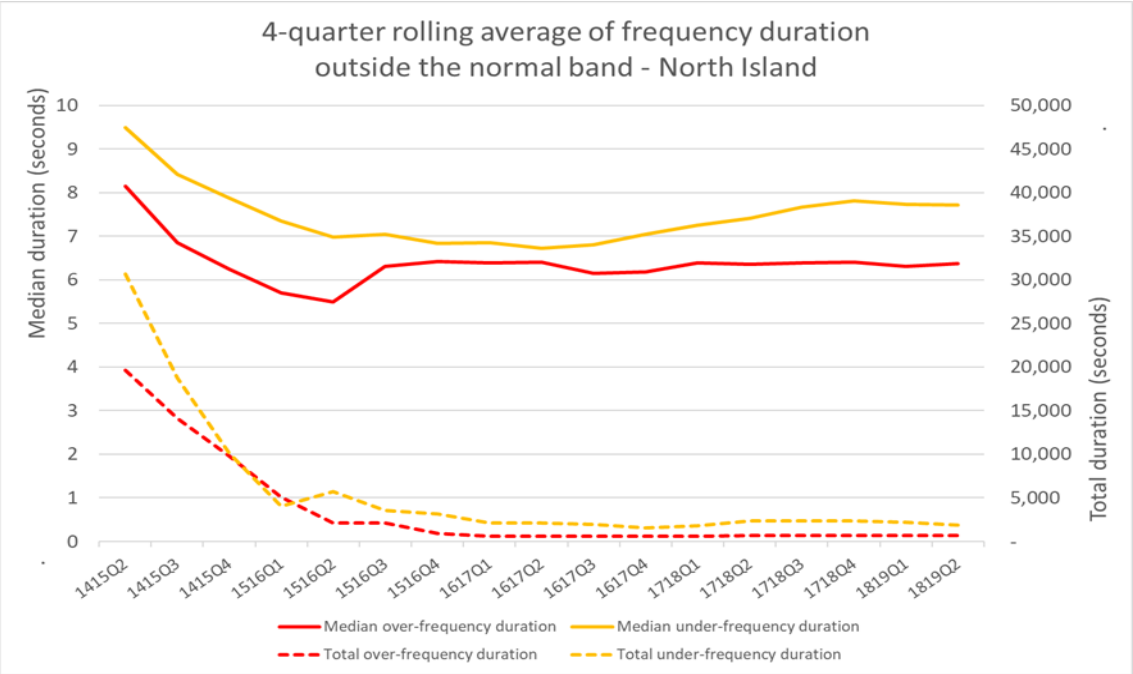
* 2018/19 Q3 contains data for January and February only

Note: These box and whisker charts show the distribution of data. The “box” represents the distribution of the middle 50% of the data, the “whiskers” indicate variability, and outliers are shown as single data points.

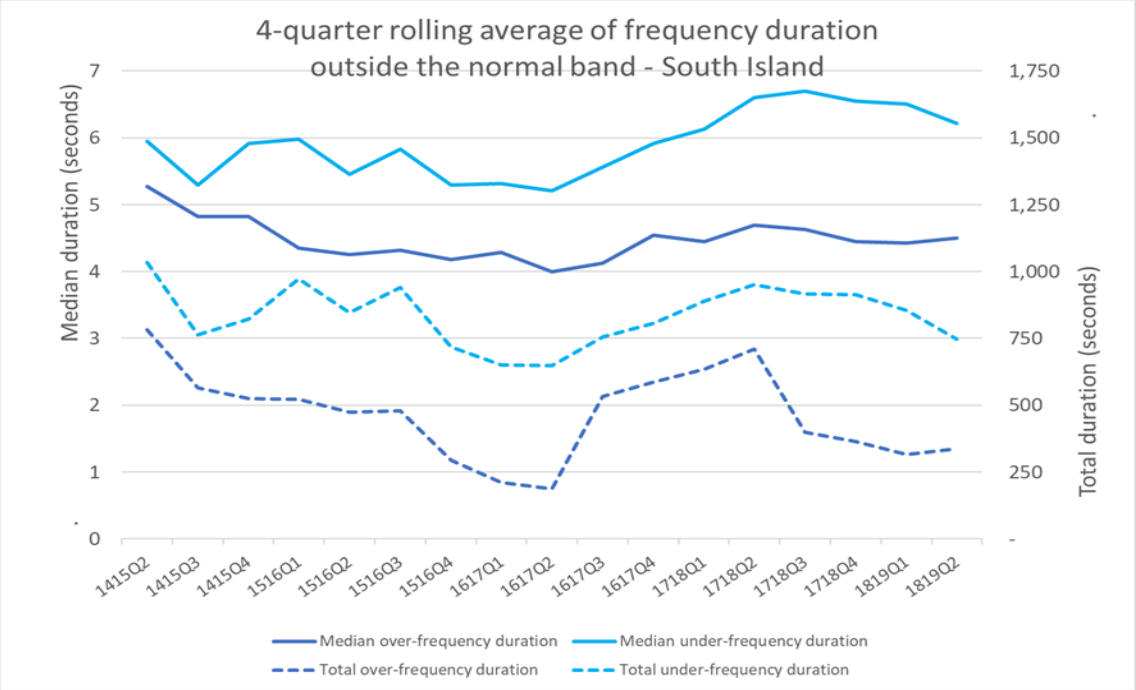
11.2 Recover quickly from a fluctuation (Time)

The following charts* show the median and total duration of all the momentary fluctuations above and below the normal band for each island. The information is shown as a 4-quarter rolling average to illustrate trends in the data

North Island



South Island

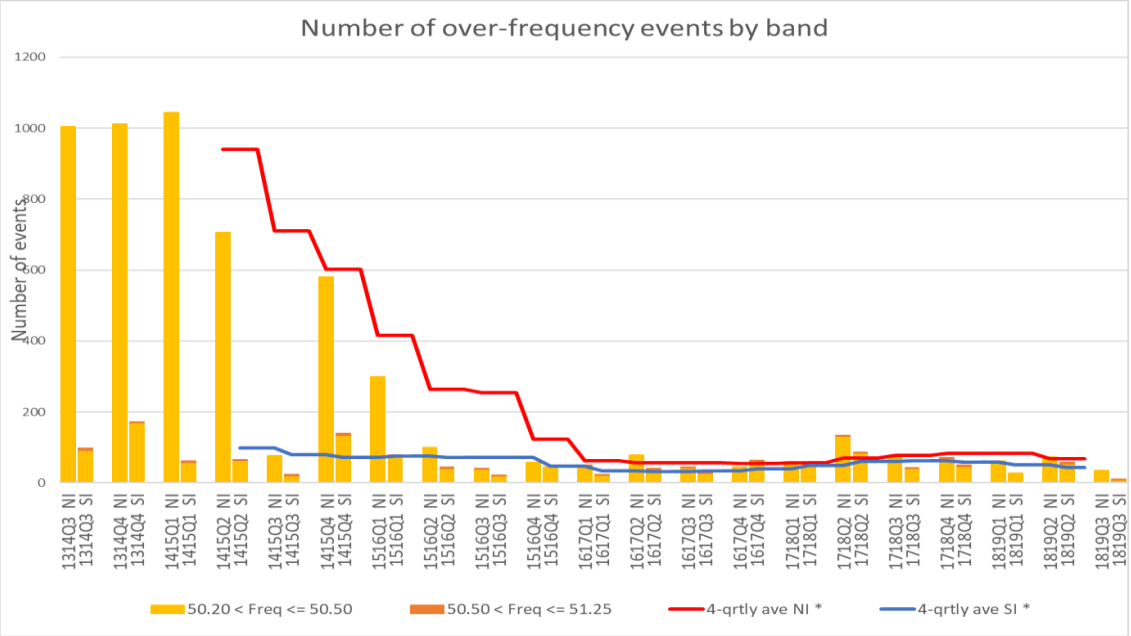


* These graphs have not been updated since 2018/19 Q2; they will only be updated at the end of each quarter

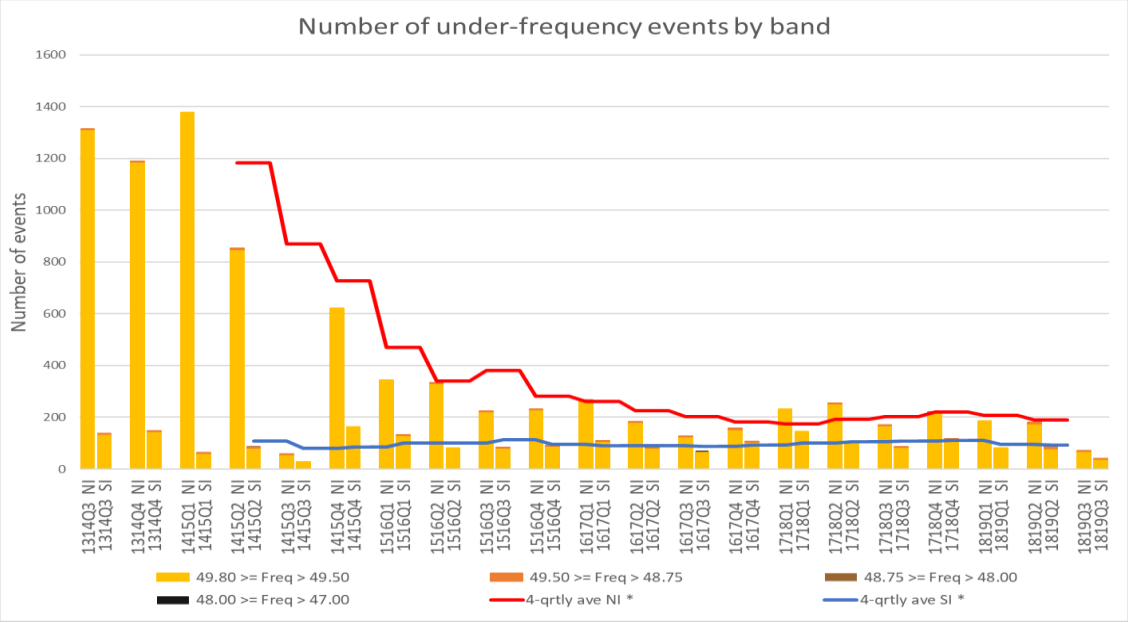
11.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

The following charts show the number of momentary fluctuations outside the frequency normal band, grouped by frequency band, for each quarter since 2014. The information is shown by island, including a 4-quarter rolling average to show the prevailing trend.

Over-frequency events



Under-frequency events



Note: The 2018/19 Q3 contains data for January and February only.

* 4-qtrly averages for NI and SI will only be updated at the end of each quarter

11.4 Manage time error and eliminate time error once per day

There were no time error violations in the reporting period.

12 Voltage management

Grid voltages did not exceed the Code voltage ranges during the reporting period.

13 Security notices

The following table shows the number of Warning Notices, Grid Emergency Notices and Customer Advice Notices issued over the last 12 months.

Notices issued	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	-	1	1	-	-	1	-	-	-	-	-	-
Warning Notice	-	-	-	1	1	-	-	-	1	-	-	-
Customer Advice Notice	4	10	12	4	2	9	9	6	20	20	16	6

14 Grid emergencies

The following table shows grid emergencies declared by the system operator.

Date	Time	Summary Details	Island
		None this month.	

15 Security of supply

Over the next 8-10 weeks we expect the risk of shortage to rise as we head into winter. The Risk Meter is currently set to Normal status, but depending on the inflows over the next quarter this may rise to Watch status, or if dry conditions persist, Alert Status. The Watch status means there is approximately a 1% chance that we do not have enough supply for the forecast demand in winter. An Alert status means there is approximately a 4% chance we do not have enough supply for the winter months.

Overall conditions were dry in February, especially in the North Island. North Island inflows were 59% of average and South Island inflows were 95% of average. National hydro storage decreased from 96% to 86% of average from the time of year.

The latest version of the Hydro Risks curves have been published on the HRC page of the Transpower website. There was a significant drop in the Hydro Risk Curves caused by the new demand forecast, prepared by Transpower, which showed a lower demand outlook.

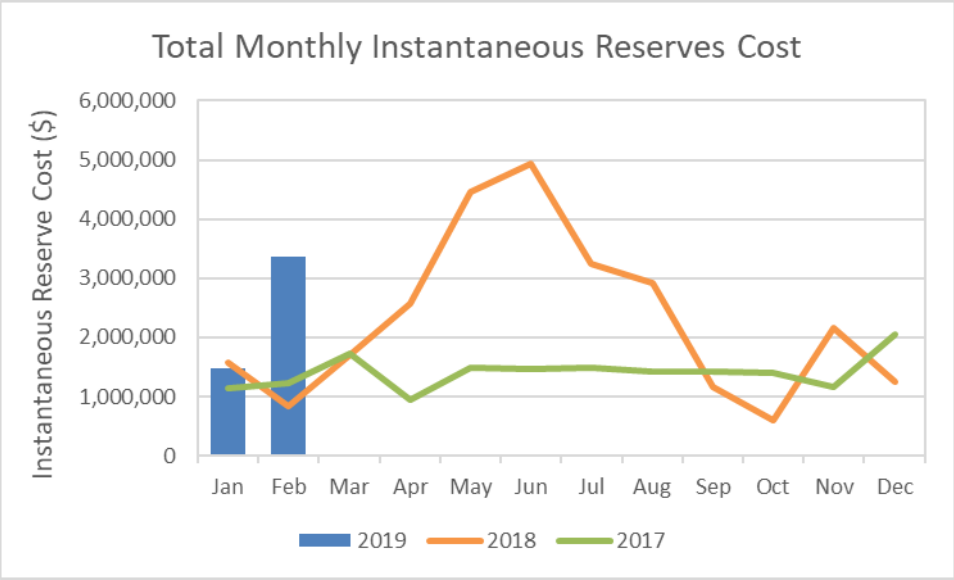
The 2019 Security of Supply Annual Assessment was published on 28 February. The key message in the report is that, based on our assumptions in the Annual Assessment, we expect to require new generation in the mid-2020s in order to maintain an efficient level of reliability.

16 Ancillary services

Ancillary services costs increased in February to $4.9m, almost double the January costs of $2.4m, and roughly the same magnitude as in July and August 2018.

This overall increase in costs was driven by two factors:

- Frequency keeping costs were particularly high for a few trading periods on 18 February. This happened when there were high constrained on costs for frequency keeping as generators were constrained for energy to allow them to keep frequency.
- Instantaneous Reserves costs were 50% higher than January for almost all generators providing spinning reserves this month as energy and reserves were highly valued. Reserve costs from thermal generation increased by 90% from the previous month.

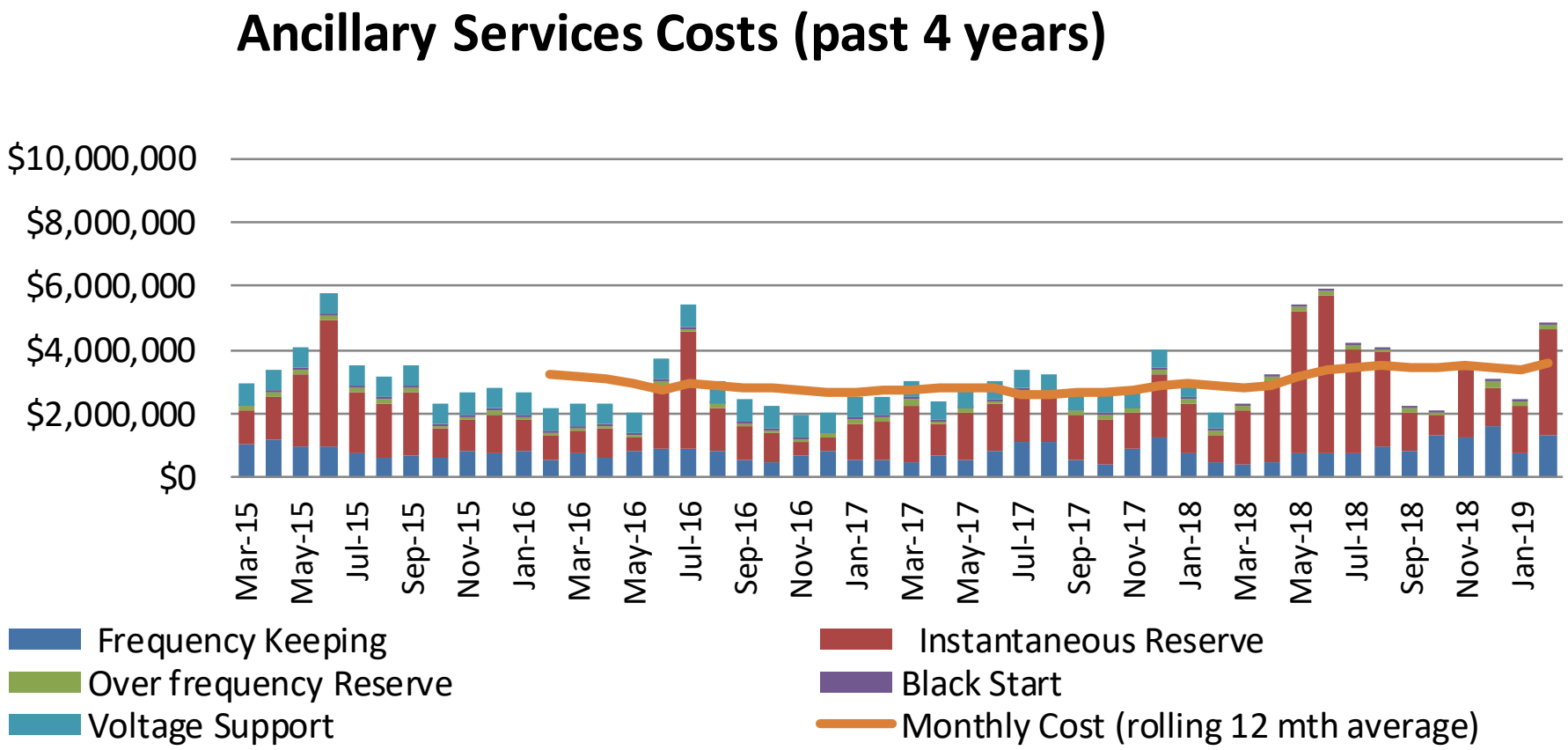


Refer to Appendix B for more detailed Ancillary Services graphs.

Appendix A: Discretion

Event Date and Time	Description
10/02/2019 13:16	MAN2201 MAN0 : For TWI Line 4 restoration.
27/02/2019 02:28	SFD2201 SFD21 : Security requirement. On for last resort TWH voltage control to provide -ve Mvar

Appendix B: Ancillary Services Graphs



Frequency Keeping (past 4 years)